

## Reliability Impacts Associated With RTO West

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This report presents a brief summary of some of the perceived reliability impacts associated with RTO West.

In order to appreciate the potential impacts, it is necessary to briefly consider the present structure within which the electric power utilities that constitute the service area function. The RTO West area is basically that covered by the Western Systems Coordinating Council. This is an area of approximately 1.8 million square miles. The evaluation of reliability within the WSCC Region is performed using a comprehensive annual assessment process based on established deterministic criteria. The member systems transmission facilities are planned in accordance with the WSCC Reliability Criteria for Transmission System Planning which establishes performance levels intended to limit the adverse effects of each member's system operation on others and recommends that each member system provide sufficient transmission capability to serve its customers, to accommodate planned inter-area power transfers and to meet its transmission obligation to others. The WSCC Planning Standard has been merged into the North American Electric Reliability Council (NERC) Standards. Since its inception in 1968, NERC has relied entirely on voluntary efforts and peer pressure to ensure compliance with its standards. The vast changes in the North American electric power supply industry brought about by "deregulation" appear to lead to the conclusion that voluntary compliance will not provide the level of system reliability required and presently enjoyed by North American electrical energy consumers.[1]

The NERC Assessment [1] indicates that capacity adequacy in North America will be dependent upon the timely construction of new generating facilities by merchant power plant developers. In the restructured climate, generation planning is conducted by merchant plant developers in areas that offer the greatest financial incentives. The details of demand and capacity as reported by the NERC regions are shown in [1]. There appears to be adequate generation capacity over the next ten years. It should be appreciated, however, that the announcement of a new merchant plant does not guarantee

that it will be subsequently placed in service. This is due to a number of reasons that include future market conditions, transmission access agreements and investor interest. The NERC Assessment [1] indicates that the construction of new transmission facilities continues to be exceeded by the growth in demand and generation facilities. Approximately 10,500 miles of transmission at 230kV or higher are planned for addition in North America over the next ten years. Approximately 3000 miles of these planned additions are proposed for the Western Interconnection. The 10,500 miles represents a 5.2% increase in total installed circuit capacity. Most of these additions are intended to address local transmission concerns or to connect proposed new merchant plants to the transmission grid and are not expected to have a significant impact on system capabilities to transfer electrical energy over long distances.

The new market environment and the addition of generating plants in locations not considered when existing transmission facilities were planned and constructed has resulted in transmission systems being subjected to flows in directions and magnitudes that were not contemplated when they were designed or which there are minimal operating experience. These new flow patterns have lead to an increasing number of facilities being identified as creating limits to transfers. Transmission loading relief (TLR) procedures have been required in areas not previously subject to overloads to maintain the transmission facilities within operating limits. The NERC Assessment [1] clearly illustrates that the number of TLR events (as reported to NERC) have steadily increased over the past five years as power transfers increased and the transmission system has become more fully subscribed. This is obviously system dependent, but is clearly indicative of an important emerging condition.

The Western Interconnection has characteristics that require extensive consideration if reliability levels are to be maintained. These characteristics include long high capacity transmission lines, transfer capabilities which are defined more by stability limits rather than thermal limits and where automatic or operator control actions must be taken very quickly. The system has seen a dramatic increase in the use of the transmission grid that is attributable to both load growth and market competition. The Northwest transmission system has seen greater than a 30% increase in system utilization over the past five years. There is very little margin left in the system and security limits

are being increasingly encountered. It is in this context that RTO West is being proposed.

The RTO structure as proposed is expected to be able to preserve or enhance overall system reliability by having the ability to balance the availability of transmission with the need to maintain transmission assets, weigh the needs for low cost service with those of system security, ensure that facilities and reinforcements needed for reliability are planned and constructed, and schedule facility outages to minimize their impact on the market as a whole. These issues are considered in more detail in the following section, under the designations of planning, operating and maintenance activities.

#### Planning, Operating and Maintenance Considerations

The RTO should have visibility of the entire grid and therefore the ability to plan the enhancements needed for adequate grid reliability, including stability controls. This visibility should include a more uniform adherence to reliability criteria. At the present time, the reliable operation of the Western Interconnection requires that all entities comply with WSCC Minimum Operating Reliability Criteria (MORC). The WSCC has also instituted a Reliability Criteria Agreement which sets forth certain reliability standards in which Participating Transmission Operators and Generators agree to comply through separately executed agreements under the WSCC Reliability Management System. Non-compliance with a reliability criterion under this agreement is subject to a series of monetary sanctions. The sanctions appear to provide an opportunity to move from voluntary compliance towards a more mandatory relationship. The new market environment requires the development and utilization of new system models that lead to compatible and efficient system planning. These new tools should include other approaches to address transmission system limitations and congestion issues. These approaches include location incentives to construct new generation in demand centers, implementation of advanced transmission technologies or economic incentives for customers to voluntarily reduce their demands. More innovative solutions are required in order to avoid being forced to depend on new transmission as the only solution for deteriorating system reliability. A major issue when adding major transmission facilities is the lead-time required to put these facilities in service. In the competitive market

place, the time required to construct a new generation facility after the decision to proceed is made, can be in the order of two years. This may be sufficient time to construct a minor transmission facility. It is expected that a major transmission facility could require five or even ten years to plan, design, license and construct [1]. Ensuring that reliability investments that benefit the entire operating area, are planned and made, is considered to be one of the most important functions of an RTO if reliability is to be sustained in the long term. It is not entirely clear, however, how the RTO will identify, execute and pay for necessary transmission system reinforcements and particularly those that link neighboring RTOs. Coordination difficulties at the borders between RTOs are likely to arise. A number of seam issues will have to be faced and settled. The transfer of control from utilities to RTOs must be managed to ensure reliability maintenance. There is also considerable concern that the already slow pace of transmission reinforcement may grind to a halt as new rules are developed, while pressure on the transmission system rapidly increases. RTO West will cover a very large area. Transfer of planning and operating control raises a number of issues related to size. Local reliability issues should not be sacrificed to promote greater economic efficiency and state regulators will demand action if local reliability levels are not maintained.

The continued safe and reliable operation of the transmission grid involves proper modeling, which in turn involves the collection and assembly of the required data. In the new competitive industry, some information is considered to be confidential, proprietary or commercially sensitive, while others view this information to fall under a public right-to-know. An example of this difference of opinion is seen in the refusal of some parties to provide data to NERC-GADS, which is a database of electric generator performance statistics [1]. Collection of the required statistical data is an important function that should be performed by RTO West.

In order to determine if bulk system reliability is being maintained at an acceptable level it is vital to establish a set of quantitative indices that provide an assessment at the bulk system delivery points and at the overall system level. This approach has been implemented by the Canadian Electricity Association and is used by most major Canadian electric power companies [3]. Table 1 shows the BPA Customer Point-of-Delivery (POD) Reliability Performance Indices on an annual basis for the

period 1990-2001. The table shows that the POD indices of SAIFI and SAIDI have generally decreased over this period. This information should be available for all regions of the Western Interconnection and for the system as a whole. Table 1 indicates a relatively high level of average system load point reliability that may be difficult to sustain in the new market environment. The creation of RTO West should definitely enhance the ability to establish a comprehensive load point and system reliability measurement system for the entire region. This should be an important objective of RTO West. It is extremely difficult if not impossible to make meaningful statements regarding reliability improvement or degradation without consistent quantitative load point and system reliability indices.

It is interesting to note that in a member survey [4] of the WSCC Criteria [2], the majority of the participants indicated that with the advent of open access and increasing competition, there is a need to have a common standard of reliability across the WSCC system and that the rigidly held deterministic criteria should be modified to incorporate probabilistic considerations. This view was extended to include the utilization of probability based criteria to incorporate performance indices such as the frequency and impact of a particular disturbance. The survey also indicated that the majority of the respondents did not use probability-based methods in planning their systems. The survey response provides an interesting and informative expression of individual utility viewpoints. The utilization of probability based criteria should also provide more flexible decision- making in the operating domain.

Increased visibility of the entire system should also provide the RTO with the ability to coordinate and plan the necessary stability controls to minimize wide spread system disturbances. The RTO must exercise an aggressive policy regarding controlling and limiting wide spread outages. A RTO will have the ability to take a much wider look at the system than exists at the present time and could affect required changes much more quickly than is possible with a fragmental approach. This is an important security issue that includes cascading event and system restoration considerations. The estimated customer interruption cost associated with unserved energy for the August 10/1996 system disturbance is over one billion dollars using a representative interrupted energy assessment rate of \$25/kWh. The customer interruption cost associated with the

July 2/1996 incident is almost 400 million dollars. The ability to reduce the likelihood and the extent of similar disturbances is an important potential RTO West benefit.

The risks associated with wide spread system disturbances are highly influenced by the operating conditions that exist in the system. Increasing utilization of the transmission system will enhance the likelihood of conditions that can lead to a wide spread disturbance, unless mitigation effects are aggressively pursued. These include in addition to new transmission facilities, the ability to operate the transmission system in real time within safe and secure operating limits. This must be a priority of the RTO and will require considerable planning and execution in the Western Interconnection, which covers an extremely large area. Overall coordination and control also raises security issues, which have become increasingly important since September 11, 2001.

Standardization of practices over the Western Interconnection should also include transmission line maintenance considerations and the overall coordination of these activities. Planned or scheduled maintenance is an important and necessary activity in order to reduce the rate of random facility failures. The likelihood of an independent random failure of an associated facility overlapping a scheduled outage is directly proportional to the duration of the maintenance activity. Coordination that reduces the duration of planned outages has obvious benefits from a load point or system point of view. Figure 1 shows some line availability data for BPA's "most important" lines over a ten year period. This figure reflects the lost availability due to planned outages only, for 207 lines of Importance Risks 1 and 2. The figure shows increased line availability over the last five years. BPA attributes this to increased coordination in the various tasks conducted by the groups involved in the transmission facility maintenance activity. The coordination of multiple simultaneous maintenance activities can have a significant impact on load point and system adequacy and security. The system is vulnerable to disturbances under high order simultaneous maintenance conditions. The system vulnerability can be reduced by active maintenance coordination. At the present time, planned outages are posted for view but not necessarily coordinated in great detail. The RTO should provide planned outage approval based on potential system impact studies conducted through a comprehensive and transparent process. In view of the significant demands placed on the transmission system under the new deregulated environment,

coordinated transmission facility maintenance can have a significant effect on overall system reliability. A thorough analysis of coordinated maintenance should also include the expected availability of merchant and utility generators. This could involve confidential information that must be handled with care by the RTO. This policy is utilized by the Transmission Administrator in Alberta, Canada. Transmission line maintenance also incorporates right-of-way considerations. Practices in this regard should be standardized and incorporate the vegetation management studies conducted after the August/1996 major system disturbance.

There are many difficulties associated with a transition from the present utility structure to operation under RTO West. The new market environment and the increasing limitations associated with existing transmission systems have created a situation that requires overall direction and control. These requirements can be achieved through a RTO structure.

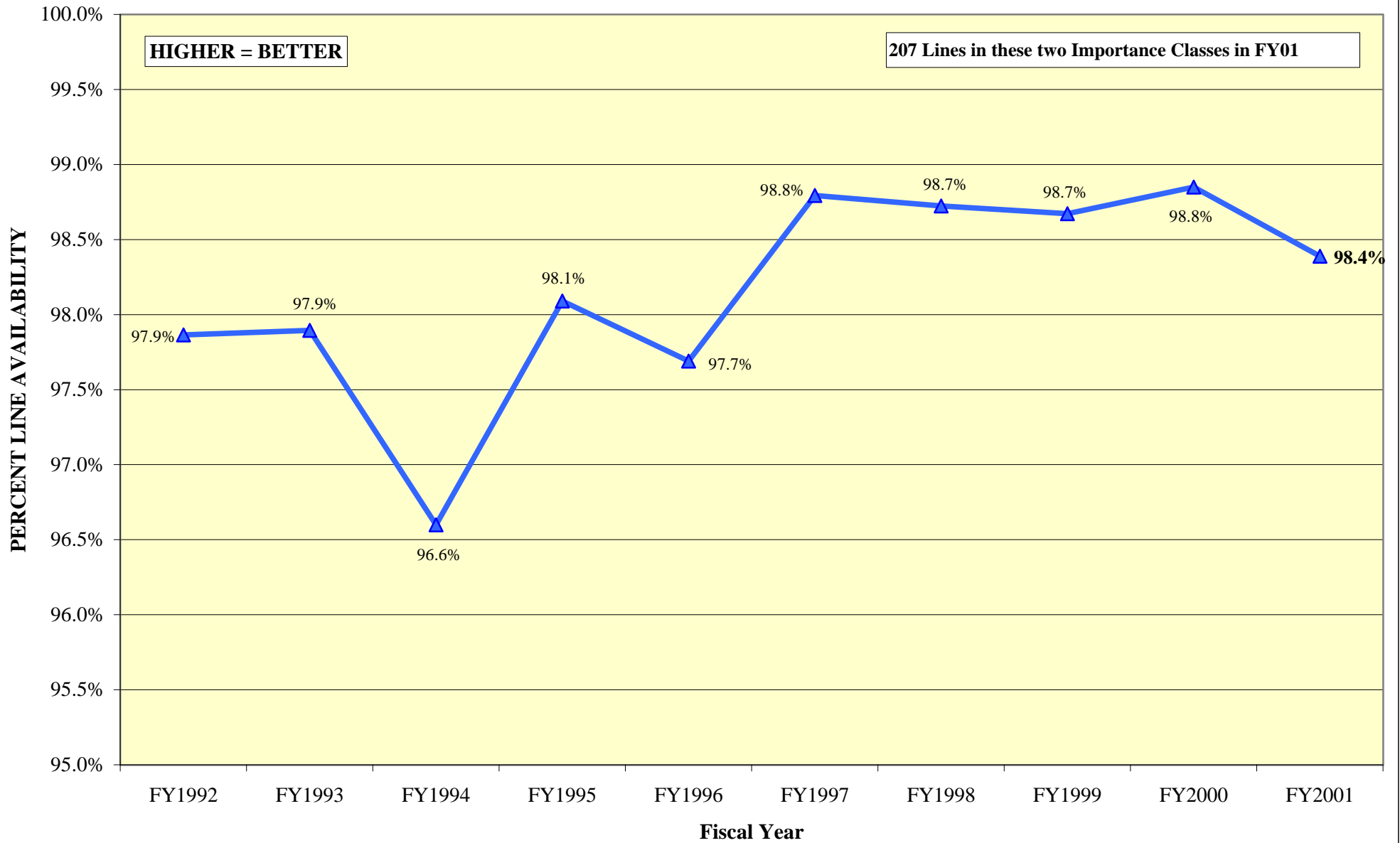
#### References.

1. NERC "Reliability Assessment 2001-2010-The Reliability of Bulk Electric Systems in North America", October 16, 2001.
2. WSCC "Reliability Criteria for Transmission System Planning", August 2001
3. CEA "Bulk Electricity System Delivery Point Interruptions and Significant Power Interruptions – 1996-2000 Report", August 2001.
4. WSCC "Member Input Survey for the Comprehensive Review of the WSCC Reliability Criteria for Transmission System Planning", June 1996.

# LINE AVAILABILITY FOR BPA's "MOST IMPORTANT" LINES

FY92 - FY01: FULL FISCAL YEARS

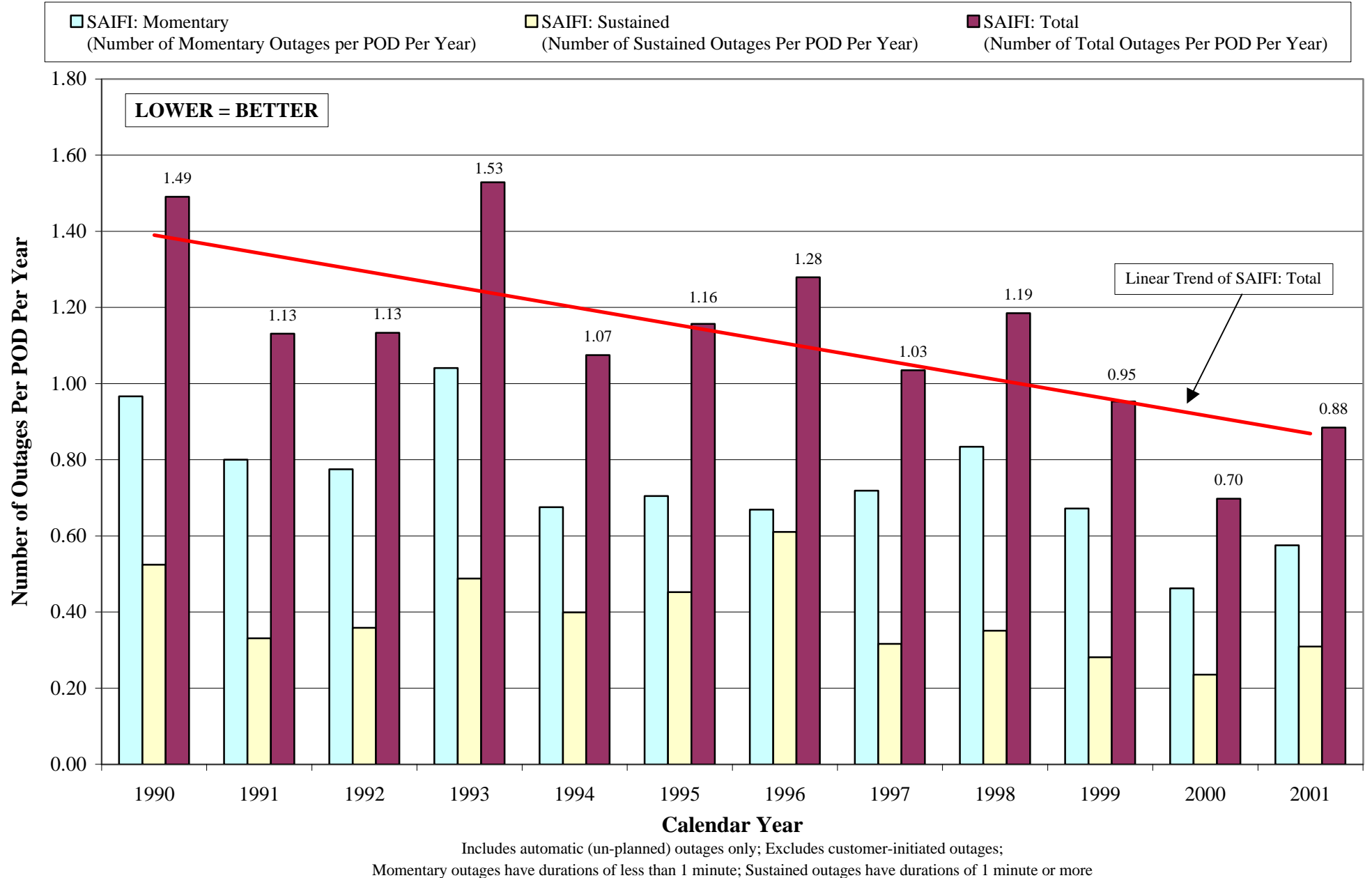
(Reflecting lost availability due to Planned outages only, for all lines of Importance Ranks 1 & 2 only)



(Line Availability = % of time that lines of Importance Ranks 1 or 2 were available for service, excluding periods of Planned outages)

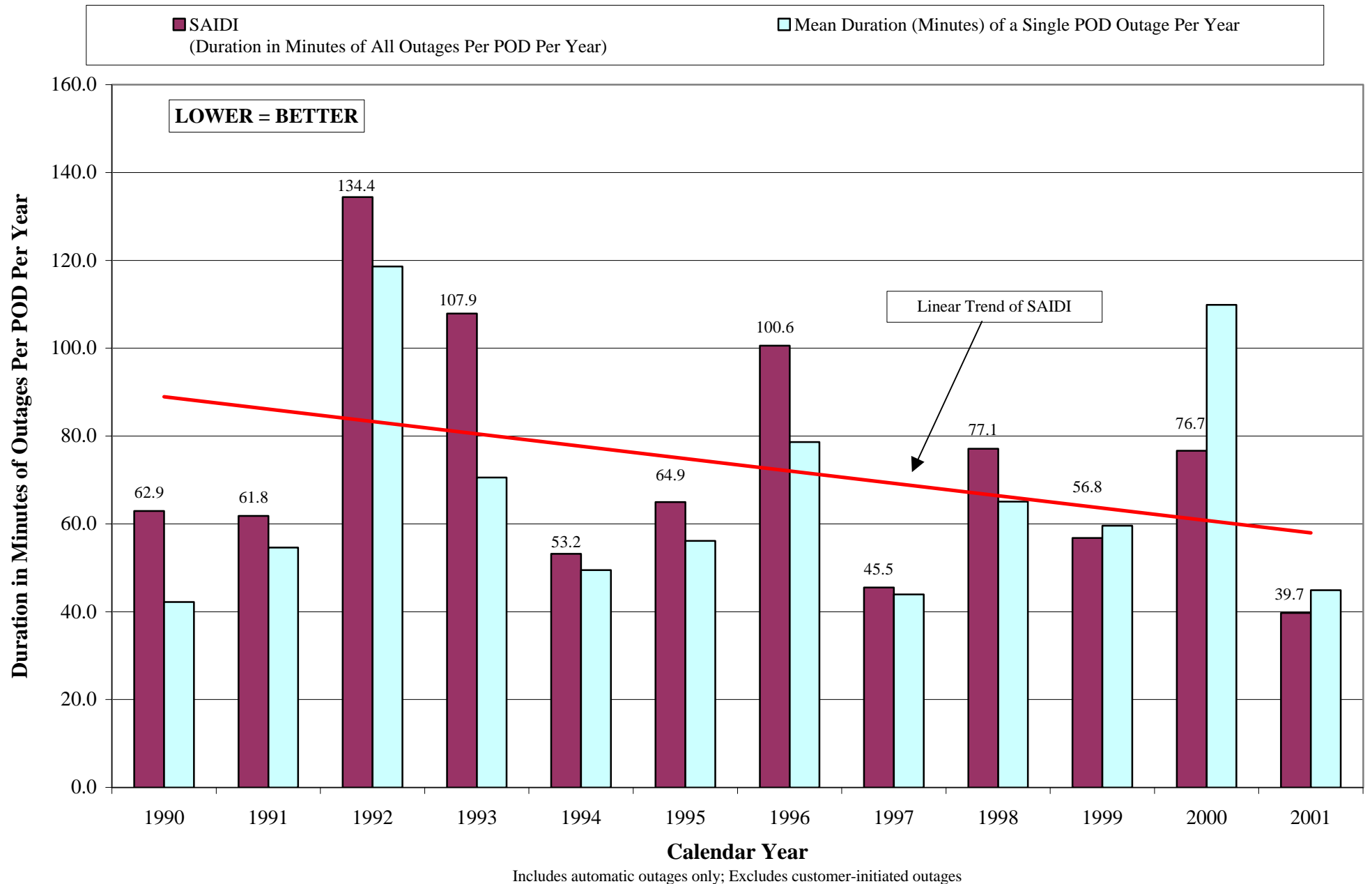
# BPA Customer Point-of-Delivery Reliability Performance: 1990-2001, By Year

## Measures Of Outage Frequency



# BPA Customer Point-of-Delivery Reliability Performance: 1990-2001, By Year

## Measures Of Outage Duration



**BPA Customer Point-of-Delivery (POD) Reliability Performance: 1990-2001, By Year**  
**Based on Measures of Outage Frequency (SAIFI) and Duration (SAIDI)**

Includes automatic (un-planned) outages only

Excludes customer-initiated outages

Momentary outages are those with duration of less than 1 minute; Sustained outages: 1 minute or more duration

BPA Transmission Business Line/Operations and Planning/25Jan02

Calendar Year	Number of Valid PODs During Year					SAIFI:						
		Number of Momentary POD Outages	Number of Sustained POD Outages	Number of Total POD Outages	Duration (Minutes) of POD Outages	Momentary SAIFI: Sustained (Number of Momentary Outages per POD Per Year)	SAIFI: Sustained (Number of Sustained Outages Per POD Per Year)	SAIFI: Total (Number of Total Outages Per POD Per Year)	SAIDI (Duration in Minutes of All Outages Per POD Per Year)	Mean Duration (Minutes) of a Single POD Outage Per Year	% of PODs With > 4 Outages (Sustained or Momentary)	% of PODs With > 150 Minutes of Outage Duration
1990	1029	994	540	1534	64732	0.97	0.52	1.49	62.9	42.2	11.2%	8.1%
1991	1022	818	338	1156	63162	0.80	0.33	1.13	61.8	54.6	7.1%	4.7%
1992	1029	797	369	1166	138258	0.77	0.36	1.13	134.4	118.6	7.4%	6.1%
1993	1031	1073	503	1576	111198	1.04	0.49	1.53	107.9	70.6	11.5%	9.7%
1994	1030	696	411	1107	54785	0.68	0.40	1.07	53.2	49.5	6.7%	7.2%
1995	947	667	428	1095	61479	0.70	0.45	1.16	64.9	56.1	8.4%	8.3%
1996	918	614	561	1175	92322	0.67	0.61	1.28	100.6	78.6	8.2%	15.1%
1997	916	658	290	948	41651	0.72	0.32	1.03	45.5	44.0	5.6%	5.5%
1998	906	756	318	1074	69896	0.83	0.35	1.19	77.1	65.1	8.5%	4.6%
1999	896	602	252	854	50882	0.67	0.28	0.95	56.8	59.6	6.1%	4.7%
2000	891	412	210	622	68340	0.46	0.24	0.70	76.7	109.9	2.7%	5.2%
2001	883	508	273	781	35065	0.58	0.31	0.88	39.7	44.9	4.8%	4.8%